EXHIBIT L

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From: Joshi, Nikhil[/O=APC/OU=DOMESTIC/CN=RECIPIENTS/CN=QYO331]
Sent: Fri 9/5/2014 8:37:51 PM Coordinated Universal Time
Subject: Shenandoah flow assurance report and impact on concept selection
Attachment: 20140905-Case_for_Dry_Tree_Development.docx

Team,
Please find attached the flow assurance report and its impact on concept selection.

I would appreciate your review and feedback please.

Thank you. Best Regards,
Nikhil

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537

Anadarko Petroleum Corporation

ANADARKO SHENANDOAH BASIN

INTERNAL DRAFT - CONFIDENTIAL

Flow Assurance Impact on Shenandoah Concept Selection

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TABLE OF CONTENTS

1.0 BACKGROUND

Shenandoah discovery is in the deepwater blocks of Walker Ridge 51 and 52 in water depth of 5,750 ft. There are two wells drilled in the reservoir with further delineation underway. A summary of the properties of the fluids encountered is presented in [REF _Ref271181394 \h]. As observed in the table, the fluids are very similar to each other in each well. However, differences in fluid properties are observed between fluids for WR 51 #2 and WR 52 #1BP2 for the corresponding zones.

Another significant measurement observed is the high asphaltene onset pressure at the reservoir conditions in the range of 11,500 – 13,500 psi.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1]: Summary of fluid properties

WR 51 #2 (Appraisal Well) (Less than 1wt% OBM in ALL samples)

	MD (Ft)	P res (Psia)	T res (F)	Psat (Psia)	API	GOR (scf/stb)	FVF (bbl/stb) Res/Sat	Viscosity (cp) Res/ Sat	AOP (Psia) @ Tres	WAT (F)
UW2	29,329	22,798	197	3,618	35.2	1,119	1.64/1.89	0.99/0.40	11,793	67
UW 3	29,576	22,906	200	3,731	35.7	1,122	1.42/1.68	0.89/0.38	N/A	74
UW3	29,791	22,981	202	3,611	35.5	1,147	1.41/1.67	0.89/0.39	N/A	67
UW3	29,907	23,024	203	3,717	33.5	1,318	1.38 / 1.61	0.88 / 0.38	11,496	49
LW A	30,010	23,067	204	3,666	36.5	1,151	1.38 /1.61	0.91/0.31	N/A	70
LW A	30,181	23,134	205	3,837	35.7	1,210	1.43/1.67	0.84/0.37	11,908	53
LW B	30,323	23,185	207	3,797	35.6	1,237	1.46/1.71	0.90/0.55	11,867	58
LW C	30,589	23,301	210	3,883	35.4	1,448	1.47 / 1.73	0.48 / 0.47	11,719	59
LW D	30,892	23,497	212	4,344	36.6	1,819	1.57 / 1.89	0.49 / 0.27	13,480	70
LW E	31,068	23,663	214	2,969	24.3	734	1.2 / 0.6	1.2 / 0.6	5,545	72

WR 52 #1BP2 (Discovery Well) (Currently not used for any workflow)

	MD (Ft)	P res (Psia)	T res (F)	Psat (Psia)	API	GOR (scf/stb)	FVF (bbl/stb) Res/Sat	Viscosity (cp) Res/Sat	AOP (Psia) @ Tres	WAT (F)
LW D	29,348	22,635	190	3,168	26.3	867	1.23/1.43	3.4 / 0.9	8,465	79
LW E	29,620	22,892	190	3,165	26.1	852	1.24/1.41	3.1 / 1.0	8,635	91

1.1. Objective of Work

There are two objectives of this work:

1. Present the flow assurance results to-date
2. Evaluate the impact of flow assurance results and production challenges on concept selection

With the current findings, various options are being considered for the development of this deepwater resource including the following with several variations for each case:

3. dry tree
4. wet tree / subsea

While detailed engineering with schedule and costs evaluations are pursued, the objective of this paper is to discuss high-level advantages and disadvantages between dry tree and subsea options and offer suggestions for concept development.

2.0 FLOW ASSURANCE RESULTS

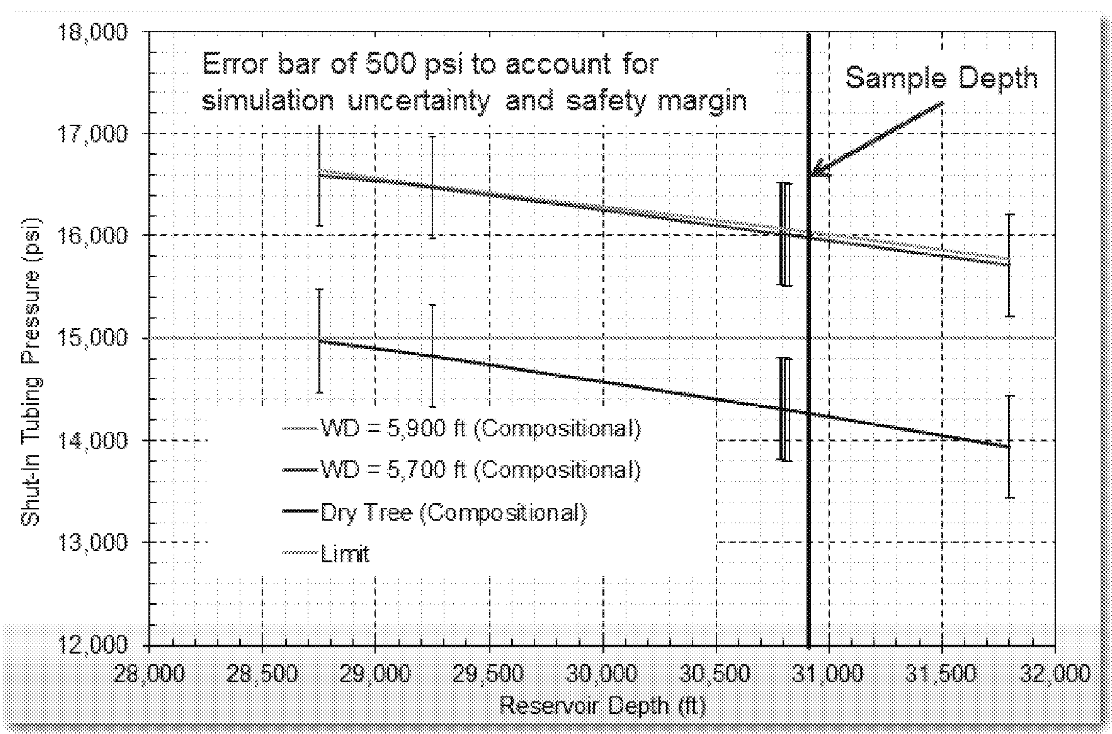
2.1. Maximum Shut-In Tubing Pressure

As observed in [REF _Ref271181394 \h], the reservoir pressures for Shenandoah sands are relatively high. Hence, there was a concern on the methodology to be used to determine maximum shut-in tubing pressure. Schlumberger software OLGA version 7.3 was used to conduct this determination along with Calsep's PVTSim version 20.1 to generate a tuned equation of state model. The steps involved in determining the maximum shut-in tubing pressure (SITP) were as follows:

- Choose LW-D sample since it has the highest gas-oil ratio (GOR) and would result in the highest SITP.
- QA/QC the lab PVT report from Core laboratories and use it to tune an equation of state (EOS) model.
- Use the EOS model to predict reservoir pressure as a function of reservoir depth to simulate compositional gradient across the reservoir. The possible upper and lower bounds of the reservoir were obtained from the reservoir team.
- Develop a wellbore with appropriate reservoir depth and 3 options:
    - Subsea tree with a water depth of 5,900 ft
    - Subsea tree with a water depth of 5,700 ft
    - Dry tree
- Simulate each variation of composition across the reservoir with the above options.

The result of the simulation is presented in [REF _Ref397693394 \h]. As observed from the figure, all subsea options have a SITP that is above 15,000 psi and the dry tree option has a SITP approaching 15,000 psi at the crest of the reservoir (shallower depth). Therefore, it is conclusive that Shenandoah development would require greater than 15,000 psi equipment.

Figure [SEQ Figure * ARABIC]: Maximum Shut-In Tubing Pressure (SITP)



2.2. Flowline Sizing

For a subsea development, the two primary selection criteria for line sizing are:

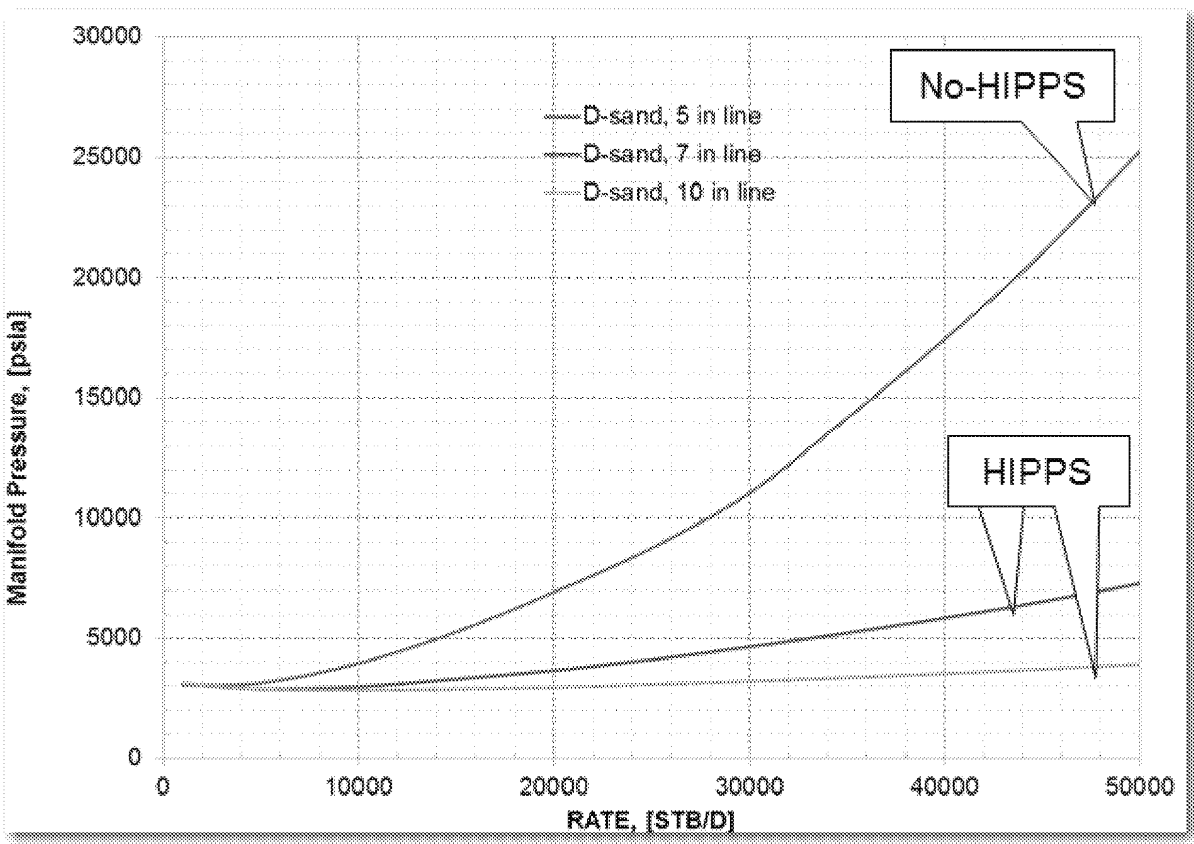
- Minimize pressure drop in the flowline;
- Maintain velocities below erosional limits.

To determine pressure drop in the flowline, LW-D fluid properties were selected because it had the highest GOR as compared to the other fluids. The following scenarios were considered for a subsea development:

- No high-integrity pressure protection system (HIPPS) which limits the flowline ID to 5.125".
- With HIPPS, subsea choke at the tree and a gathering system downstream of the choke to minimize number of flowlines and risers to the host:
    - Flowline ID = 7" (15,000 psi rated)
    - Flowline ID = 10" (10,000 psi rated)

Assuming arrival pressure of 1,800 psi, the pressure subsea at a gathering manifold was simulated and the results are in [REF _Ref397693813 \h]. It is desired to keep the pressure at the subsea manifold to be ~5,000 – 7,000 psi to minimize back pressure on the wells and optimize recovery. As seen in the figure, a 5.125" ID flowline without HIPPS results in very high pressures at the manifold and it is unrealistic. Both the 7" and 10" ID flowlines require relatively low pressures to allow high flowrates through them.

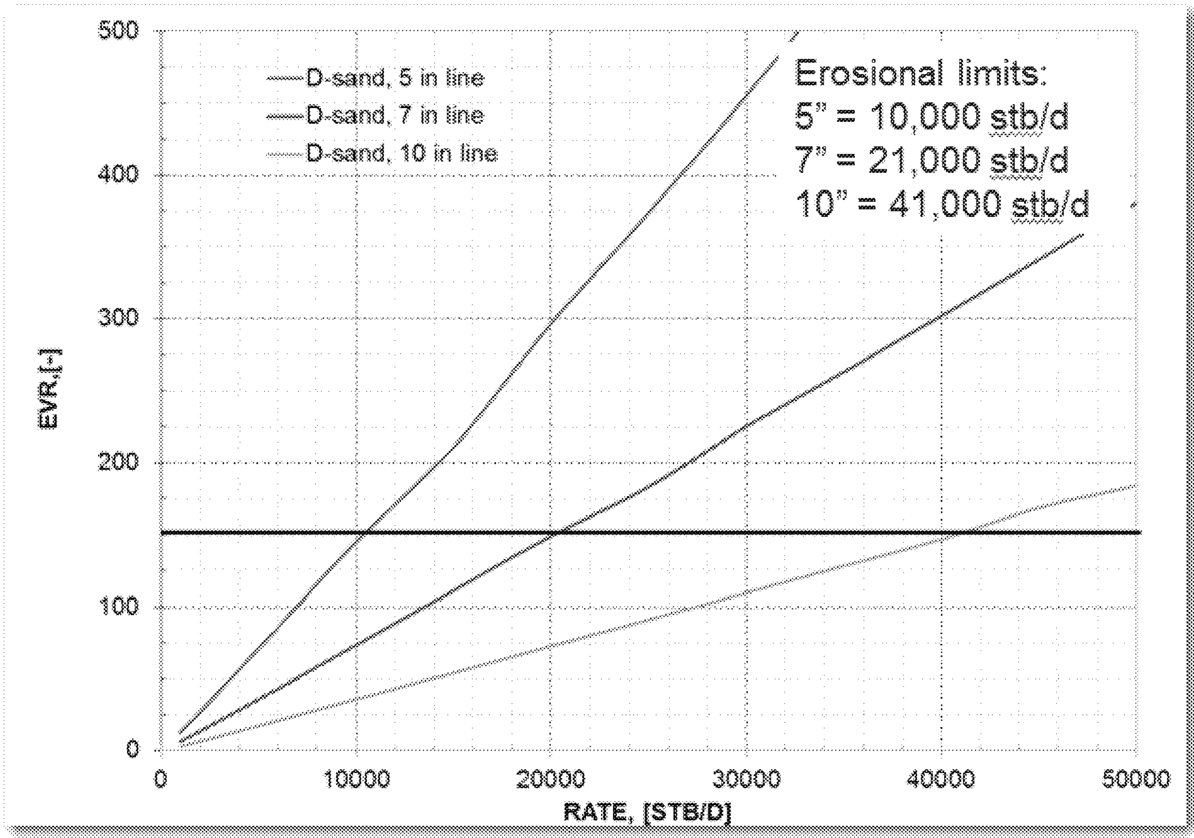
Figure [SEQ Figure * ARABIC]: Flowline pressure drop results



In addition to the pressure drop, erosional velocity limits are also to be considered. Assuming sand control is deployed, the erosional velocity limit is based on C-factor of 150 for carbon steel flowlines. Hence, C-factor (EVR) was calculated for the 3 options presented above and the results are presented in

[REF _Ref397694122 \h]. As observed in the figure, a 10" ID flowline is the best option for a subsea development to minimize frictional pressure drop as well as minimize erosional velocities. There are other considerations such as slugging and heat retention which are to be considered before the line sizing is finalized but they are operational optimizations that can be undertaken at a later stage.

Figure [SEQ Figure * ARABIC]: Erosional velocity with sand control



3.0 DEVELOPMENT CHALLENGES

This section discusses the following significant concerns that should be considered for concept development selection:

1. Sand control / production
2. Vertical Connectivity and Production Surveillance
3. Asphaltene mitigation
4. Reservoir compartmentalization

3.1. Sand Control / Production

For Miocene reservoirs, cased-hole gravel pack with sand control screens has been the default completion strategy. Since Shenandoah reservoir has multiple sands and it is expected that multiple zones may need to be commingled downhole. To account for this complexity, open hole completion is contemplated without sand control measures because of the difficulty to implement sand control for several sands that are commingled. Open hole completion without sand control may result in sand production, which is currently not quantified. To determine likelihood of sand production and produced sand quantity as well as the particle size, whole core samples are required. It is expected to collect whole core samples in the upcoming appraisal wells and get appropriate testing done.

The core analysis will incorporate testing on the collected samples as well as simulations that take into account the measured properties. It is known that the composition of side wall core samples collected is very different from a typical Miocene core. An example of the comparison is presented in [REF _Ref397675356 \h] below. As seen in the table, the Shenandoah side wall core has a significantly higher clay content which may be susceptible to mobilization and hence, production.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1]: Comparison of core composition

	Miocene	Shenandoah-2
Quartz	75 – 90	44
Feldspar	1 – 5	24
Clay	4 – 8	19

After the whole core samples are analyzed, the likelihood of sand production can be determined but quantity and particle size of sand that could be produced will be uncertain.

In such a case where production of sand is to be expected, the impact of sand production can be mitigated in the following possible methods:

1. Downhole sand screens
2. Design downhole, subsea and topside equipment to allow sand production
3. Minimize bends in the production system to minimize impingement of produced sand on the flow path tubulars

Impact of sand production on erosion of tubulars has been a topic of research for several years. The University of Tulsa has an industry leading joint industry project (JIP) and has developed software named SPPS. The software can be used to determine erosional impact on various pipe bends.

3.1.1 Downhole Sand Screens

If downhole sand screens are deployed and sand production is expected, it is conceivable that the sand screens would withhold most of the mobilized large sand particles. Thus, minimal sand erosion is to be expected for the tubulars because of relatively small (less than 50 microns) sand particles that are allowed through the sand screens. However, the sand screens may get plugged with produced sand and

such a scenario may be difficult to remediate.

Solvent injections can be undertaken to remediate the sand plugged screens by pushing the sand away from the screens and opening sufficient screen surface area for reservoir fluids to flow. However, such a solution is expected to be temporary because the sand pushed away will produce and plug the screens again.

3.1.2 Erosion Calculations with Sand Production

The most impact of sand production with respect to erosion is expected for a subsea development where there are significant bends at the subsea tree and other subsea architecture. A dry tree development is not expected to have as many bends. It is also assumed that most of the bends which may be impacted by sand impingement in a dry tree development are accessible at the producing host and can be replaced with time. Such a replacement program for a subsea development is considered impractical and costly.

In order to bound the impact of sand production on the erosion of tubulars, University of Tulsa developed model was used to simulate maximum production rate expected. The smallest ID of 5.125" in a subsea development is in the HIPPS region and it is expected to the most impacted with sand production. A summary of the possible flow rates and assumptions used is presented in [REF _Ref397677312 \h] below and it should be noted that this is work in progress and not finalized. As seen in the table, the sand particle concentration and its size significantly impact the allowable oil production for each flowline size. A general conclusion can be derived from this work is that if a thorough understanding of the expected particle size and concentration is not developed, the capability of the subsea system is highly uncertain and a significant project risk.

In addition, it is postulated that there will be significant uncertainty in the predicted particle size and concentration even after whole core samples are analyzed and appropriate simulation work done.

<u>Hence, the uncertainty in erosion impact discussed here is foreseen to be high resulting. Therefore, there is high uncertainty in deliverability and reliability of a subsea development without sand control.</u>

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1]: Flow rate limitations with sand production

Particle size (microns)	250	50
Particle concentration (%)	1	0.01
Size (inch)	Low (stb/d)	High (stb/d)
5.125	5,000	35,000
7	7,000	80,000
10	9,000	100,000+

* **Work in progress**

Assumption: Allowable erosional limit of 3 mils per year (mpy)

3.1.3 Minimize Bends (Dry Tree)

As mentioned in the discussion above, if sand production cannot be quantified, a possible mitigation is to minimize the bends in the production flow path. <u>This is only feasible if appropriate dry tree design is concerned for development.</u>

3.2 Vertical Connectivity and Production Surveillance

As discussed in earlier sections, downhole commingling of various sands is expected to be the base case for Shenandoah development. For the well in WR 51#2 well, dead oil samples from each zone was analyzed for vertical connectivity as well as compositional similarity. The compositional work was intended as proof of concept to be used if downhole commingling is pursued.

3.2.1 Vertical Connectivity

Based on the completed analyses detailed in the Weatherford report BH-71208 issued in July 2014 titled "Geochemical Comparison of MDT Oils from Walker Ridge Block 51", the following sands are expected to be vertically disconnected from each other:

- Upper Wilcox 2 (UW-2)
- Lower Wilcox C (LW-C)
- Lower Wilcox D (LW-D)
- Lower Wilcox E (LW-E)

However, the other 3 sands encountered in WR51 #2 well may possibly be vertically connected but disconnected from the above set:

- Upper Wilcox 3 (UW-3)
- Lower Wilcox A (LW-A)
- Lower Wilcox B (LW-B)

This is because the dead oil samples showed very similar characteristics for these 3 sands (UW-3, LW-A and LW-B) which are very different from all other sands. This can be interpreted as:

- They are vertically connected
- They are vertically separated but could be connected hydraulically via an aquifer or they are just similar fluids but not hydraulically connected at all

These possibilities will not be conclusively determined till hydrocarbon production occurs from these sands or hydraulic connectivity is established by pressure observations during drilling of appraisal wells. Even if hydraulic connectivity is established, the nature of depletion expected from these sands won't be known till they are produced.

3.2.2 Production Surveillance

In a case where downhole commingling of UW-3, LW-A and LW-B is pursued, it is imperative to understand contributions from each of these zones for future drilling and development of the field including determination of cross flow across sands in each well. The zonal contributions can be determined using one of the following methods:

- Downhole distributed temperature sensors (DTS) across each sand face – the monitoring of temperature across the perforations <u>may</u> provide insight into the production rate from each zone.
- Unique tracers installed with completion screens for each zone. This is new technology that has been under trial. One of the significant limitations with such technology is that a relatively long shut-in is required for each well (24 – 48 hours) and frequent samples are to be collected of the produced fluids after shut-in. Such a technology holds promise but further assessment needs to be done to confirm:
  - Whether completion designs allow accommodation of such devices;
  - The technology will be effective to determine zonal contributions.

3.2.3 Production Logging

If subsea development is pursued, determining zonal contributions using a production log would be challenging to justify because a rig with flowback equipment will be required. <u>If a dry tree development is pursued, production logging is expected to be available to determine zonal contributions, especially for the zones which are similar (UW-3, LW-A and LW-B). Such access to production logging would</u>

significantly improve the understanding of the reservoir and provide valuable information for life of field development.

3.3 Asphaltene Mitigation

As observed in [REF _Ref271181394 \h], the asphaltene onset pressure (AOP) measurements for most of the WR51#2 sands is high in the range of 11,500 – 13,500 psi at reservoir temperature. Such a high asphaltene onset pressure poses the following risks:

- With production, as the reservoir pressure depletes below the AOP, asphaltene precipitation and deposition in the reservoir could be expected. Such a phenomenon may alter:
  - Permeability and porosity change in the reservoir;
  - Near wellbore formation damage resulting in productivity decline;
  - Wettability changes that may result in higher irreducible oil saturation;
  - Overall recovery decline for each well.
- Pressure is expected to fall below AOP in the tubulars, especially in the tubing which would result in asphaltene precipitation and deposition. Asphaltene deposition in the tubing is a significant risk resulting in additional pressure drop and eventual plugging of a producing well.

The above risks are discussed in detail below.

3.3.1 Asphaltene precipitation in the reservoir

Asphaltene precipitation in the reservoir can only be avoided by maintaining the reservoir pressure above AOP. This can only be done by a pressure maintenance mechanism which would entail injection of gas and/or sea water in the reservoir. Gas injection in the reservoir would result in significant aggravation of asphaltene precipitation in the near wellbore area of the injector and hence, it is not considered at this stage. Sea water injection is the only plausible case to maintain reservoir pressure above AOP.

However, pressure maintenance using sea water is highly uncertain because of reservoir compartmentalization, uncertainty in the hydraulic connectivity of the reservoir and porosity and permeability variations that are unknown. By conducting additional appraisal drilling, these uncertainties can be reduced but not eliminated. Therefore, water injection is not a 100% reliable method to maintain reservoir pressure and it cannot be proven till it is implemented.

If water injection is considered for a pilot to address the uncertainty of hydraulic connectivity, pressure maintenance and flood efficiency, the water to be injected has to be 1.4 times or higher as compared to the production rate from the flooded reservoir. As with production wells, the injector wells are expected to have multiple sands. Controlling water injection rate into a given sand is challenging (if not impossible) unless smart completions with rate control devices are implemented downhole. Such devices significantly increase the complexity of the completions and lead to high failure possibilities.

Therefore, water injection to maintain pressure cannot be considered as a reliable mitigation measure for asphaltene precipitation and deposition in the reservoir for concept selection.

Hence, it is imperative that the potential impact of allowing the reservoir pressure below AOP be studied and considered for concept selection and field development. This is a risk the project team should be willing to take.

3.3.2 Asphaltene precipitation near wellbore

In addition to the reservoir, the near wellbore pressures are expected to decline not only because of depletion but also because of drawdown required to produce the required rate. Hence, asphaltene precipitation and deposition near wellbore is a strong possibility. This phenomenon would result in productivity decline for the well and eventual loss of hydrocarbon recovery expected. To mitigate such an

issue, asphaltene squeeze treatments are being considered. The squeeze treatments are new technology and not field proven. Also, the limitation of a squeeze treatment is the length of time that it is effective. In high production rate cases, the asphaltene squeeze is effective for 3 – 12 months. While it is conceivable to repeat squeeze treatments, their effectiveness may be greatly reduced if deployed via production umbilicals as compared to a rig (coiled tubing deployment).

The near wellbore formation damage caused by asphaltene deposition can also be mitigated using solvent treatments such as xylene. These treatments have been effective in increasing instantaneous productivity of a well but they are short lived. Based on experience, the productivity of the well starts declining immediately after the solvent treatment and returns to pre-treatment levels within 30 – 45 days.

<u>Therefore, asphaltene squeeze and/or solvent stimulations are not a reliable method to mitigate asphaltene deposition near wellbore.</u>

3.3.3 Asphaltene deposition in the wellbore

As described above, asphaltene deposition in the wellbore is expected and if left unmitigated, it can lead to complete wellbore plugging. Such a risk can be partially mitigated by the use of downhole chemical injection of asphaltene inhibitor/dispersant. The chemical injection line is required to be as close to the sand perforations as possible to minimize the un-treated length of the tubing. However, it is known that chemical injections are only partially effective in preventing deposition. Improved effectiveness ir being pursued by developing new chemistries but such a technology should be considered as new and unproven.

The deposits in the wellbore can also be removed by solvent injection such as Xylene. These measures

<u>Hence, asphaltene deposition in the wellbore may be mitigated with chemicals but significant testing is required.</u>

3.4 Reservoir Compartmentalization

It is imperative that any concept selection requires minimizing risks and maximizing hydrocarbon recovery potential. It is expected that the subsurface uncertainty will remain high irrespective of a reasonable appraisal plan. The risk of compartmentalized reservoirs may severely impair the recoverable value of any project. To mitigate reservoir compartmentalization risk, water injection can be considered to improve pressure maintenance and/or sweep efficiency in a given reservoir. However, water injection is only effective once the location of the injectors and producers are optimized after obtaining production history of the reservoir.

<u>Therefore, water injection in concept select stage does not mitigate the risk of lower recovery from reservoir compartmentalization.</u>

However, implementation of artificial lift may increase recovery prospects from a given well irrespective of reservoir compartmentalization. The extent of increased recovery is still influenced by the compartments in which the producer is located. Assuming a producer in a given compartment (drainage limited to that compartment), a comparison was done to evaluate the effects of various options:

- Case 1 = depletion while maintaining flowing bottomhole pressure above AOP at 14,000 psi
- Case 2 = water injection to maintain pressure above AOP
- Case 3 = electrical submersible pump (ESP) in the wellbore located at 10,000 ft below mudline
- Case 4 = artificial lift at the sea floor (subsea separation and pumping)

The results of these evaluations are presented [REF _Ref397687060 \h] below and they were jointly developed by flow assurance and reservoir team. As observed from the table, the highest recovery is obtained in a water injection case and an ESP case. ESP deployment in a subsea well is not considered feasible because of relatively high intervention costs to replace the ESP periodically. Hence, the ESP case is only assumed to be for a dry tree development.

In addition to the recovery, a column suggesting uncertainty in recovery is added. Cases 3 and 4 have relatively low uncertainty because they are technologies deployed before and their performance can be controlled. However, recovery from water injection uncertainty is high because water injection can be controlled but the response from the reservoir will remain highly uncertain.

Also added to the table is whether the concept is successful in maintaining pressure above AOP. The only option that maintains pressure above AOP is the depletion case where the production from a well is abandoned when the flowing bottomhole pressure reaches 14,000 psi. The water injection case may be able to maintain reservoir pressures above AOP but it depends on several factors such as timing of the water injector, volume of water injected, reservoir connectivity, variation in rock properties such as porosity and permability.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1]: Recovery estimations

Case	Recovery (%)	Subsea / Dry Tree	Uncertainty in recovery	Maintain P > AOP
1	11	Subsea / Dry Tree	Low	Yes
2	24	Subsea	High	Maybe
3	23	Dry Tree	Low	No
4	20	Subsea / Dry Tree	Low	No

Therefore, if allowing the reservoir pressure to drop below AOP is an acceptable risk, a dry tree development with ESP is ideal to maximize recovery.

4.0 RECOMMENDATION

A dry tree development offers significant advantages as compared to a wet tree (subsea) development and they are discussed below.

1. Sand control / production: Unless sand control for all sands being commingled downhole is deployed, sand production is a possibility and it cannot be quantified with certainty. Sand production and high uncertainty is detrimental to a subsea development. Hence, no sand control and subsea development cannot be accommodates simultaneously. However, <u>no sand control is a manageable risk for a dry tree development.</u>
2. Vertical connectivity / production surveillance: If UW-3, LW-A and LW-B are to be commingled in the wellbore, the only reliable method to monitor production and cross flow between sands is by conducting production logging. <u>Production logs are feasible for a dry tree development.</u>
3. Asphaltene mitigation: It is farfetched in concept development stage to assume that water injection will maintain reservoir pressure above AOP. Even if pressure in reservoir is maintained above AOP, it will fall below AOP and result in asphaltene deposition in the tubing. Asphaltene deposition in the tubing cannot be easily remediated by current methods such as solvent treatments. A subsea development would result in significant cost and downtime to remediate asphaltene deposition in tubing. <u>A dry tree development would enable timely intervention and cleaning of the tubing. It would also enable stimulation options to mitigate near wellbore formation damage concerns.</u>
4. Reservoir compartmentalization: This risk cannot be mitigated in Phase1 of the project and high uncertainty will remain till production data is obtained. <u>Dry tree development enables ESP deployment to maximum recovery in Phase1 with lowest CAPEX increase.</u>

The use of dry trees also delays or eliminates the possibility of high-integrity pressure protection system (HIPPS) deployment.

In addition to the above advantages, dry tree development also helps timely (reduced downtime) intervention capability to adapt to the un-foreseen challenges during the initial life cycle of the project. Lessons learned from Phase1 dry tree development can be used to appropriately determine the best full-field development which may or may not include subsea wells.

Risks	DryTree	Subsea
No sand control		
Production surveillance		
Asphaltene mitigation (tubing and near wellbore)		
Increased recovery with lowest CAPEX increase		
Low intervention cost		

A major limitation of dry tree is the inability to reach the entire reservoir aerially. Therefore, a combination of dry tree and subsea development is possible in the future. However, lessons learned from Phase1 dry tree development would significantly improve the success of future full-field phase developments.

<u>**Therefore, a dry tree development it is recommended from a flow assurance perspective for Shenandoah Phase1 development.**</u>